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Selection and Successful Application of Jet Pumps in Mangala Oil field: A Case Study

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Abstract

This paper describes the selection, field application and performance monitoring of jet pumps in the giant Mangala field situated in the Barmer basin in Rajasthan, India. The field contains more than a billion barrel of STOIIP (Stock Tank Oil Initially in Place) in high-quality reservoirs. The field was brought on production in August 2009 and is currently producing at a plateau of 150,000 bopd. Mangala field is characterized by multi-Darcy rocks with mix to oil wet characteristics. The oil is waxy and viscous, with wax appearance temperatures close to reservoir temperature.

Jet pump has been selected as the preferred artificial lift method for the deviated wells. The base development plan included hot water flooding; this makes water heated up to 85 °C available at the well pads as power fluid for jet pumping. In order to prevent exposure of carbon steel production casing to corrosive reservoir fluid, the jet pumping process involves pumping the power fluid down the annulus and taking returns through the tubing.

The results have indicated that the jet pumps are giving required drawdown, thereby restoring the liquid productivity of the wells. In addition to restoring well production, jet pumping has also been used as an effective and fast method for cleanup of deviated wells completed with sand screens. The real time monitoring of the jet pump parameters, using Digital Oil Field (DOF), has immensely helped in efficient monitoring the pump performance and reducing the response time in case of problems.

Jet pump application has helped in restoring the deliverability of wells at high water cut for such a viscous crude. Further analysis of the pump behavior will provide insight for efficiently operating these pumps which is critical for maximizing recovery from the field at higher water cuts.

Introduction

The onshore Mangala field is located in the north-west part of India in the Barmer Basin **(Fig.1)**. The field was discovered in January 2004. The main reservoir unit in Mangala field is the Fatehgarh group, which is a very high quality quartzose sandstone reservoir, with high net to gross, high porosity and multi-Darcy permeability. The Fatehgarh sand has been sub-divided into the Lower Fatehgarh formation dominated by well-connected sheet flood and braided channel sands, and the Upper Fatehgarh formation dominated by sinuous, meandering, fluvial channel sands. Five reservoir units are recognized, named FM1-FM5 from the top downwards. FM1 and FM2 comprise the Upper Fatehgarh formation and FM3, FM4 and FM5 form the Lower Fatehgarh formation. The Fatehgarh sand properties are excellent, with porosities of 21-28% and permeability of 200 milli-Darcy (mD) to 20 Darcy (D). Average permeability is ~ 5 Darcy **(Fig.2)**.

The Mangala field has been developed with a total of 162 wells (111 oil wells, 51 water injector wells) with dedicated producers and injectors for each Fatehgarh sand member drilled from 18 well pads spread across the length and breadth of the field. For lowering infrastructure costs and land requirements, the well pad concept was used as opposed to individual well locations. Upper Fatehgarh sands (FM-1, FM-2) have been developed using inverted nine spot patterns of inclined producers and injectors. The Lower Fatehgarh reservoirs, namely FM3 and FM4 which is extremely continuous with little thickness variations and have net to gross in excess of 90%, are developed using horizontal producers and line drive injection support provided by inclined injectors **(Fig.3)**.

Mangala development producer wells have been divided into the following three categories:

1. **Horizontal producers** with ESP as a primary mode of artificial lift and jet pump as secondary mode **(Fig.4)**. The lower completion consist of 8-1/2" open hole with conventional screens / Inflow Control Device (ICD) screens and the upper completion consist of 4-1/2",13 Cr tubing with two chemical lines, one 1.5" heater string and ESP as the primary lift.

2. **Heavy producers** with Jet pump as the only artificial lift mode **(Fig.5)**. The lower completion consist of 8-1/2" open hole with conventional screens / Sliding Side Door (SSD) screens and the upper completion consist of 4-1/2",13 Cr tubing with two chemical lines, one 1.5" heater string and jet pump as the primary lift.

3. **Light producers** with Jet pump as the only artificial lift mode **(Fig.6)**. The lower completion consist of 6" open hole with conventional screens / SSD screens and the upper completion consist of 3-1/2",13 Cr tubing with two chemical lines, one 1" heater string and jet pump as the primary lift.

Heater string is designed to be used for circulation of hot water in the annulus to maintain wellbore temperature above Wax Appearance Temperature (WAT) for the self flowing and ESP lifted wells.

Artificial Lift Selection Methodology

Since the discovery of the field, various studies were conducted to understand flow assurance challenges and provide mitigation measures so as to produce the waxy field in an optimal way. Main challenges identified in selection of the artificial lift are as follows:

- High paraffinic content with very high WAT crude **(Fig. 7)** is the main challenge for downhole and surface flow assurance of the Mangala crude. This challenge was mitigated by providing a system of hot water circulation at every pad and back to the processing facility. This hot water is circulated down the wells via heater strings in all producer wells and is piped back into the well flow line downstream of the choke. The hot water circulation thus provides the advantage of keeping the crude above WAT throughout the production system.

- High in-situ crude viscosity requires hot water diluent to keep production fluid viscosity at manageable levels and to prevent wax deposition in the tubing and surface facilities.

- Formation of stable oil emulsions with onset of water production. All the laboratory work had suggested multi- fold increase in emulsion viscosity at high water cuts with inversion point in the range of 60-80 % water cut **(Fig. 8)**

- High CO_2 content in the reservoir fluid (25 mole% in gas phase) poses significant corrosion risk.

- Potential of sand production due to shallow reservoir and relatively low rock strength with Unconfined Compressive Strength (UCS) of 1600 psi, high crude viscosity and early water breakthrough.

- Low reservoir pressure and low Gas-Oil Ratio (GOR) of 120- 200 scf/stb with early water breakthrough

due to adverse mobility ratio.

The reservoir and fluid properties of Mangala crude which were critical for selection of the most suitable artificial lift are presented in Table: 1 below:

Property	Unit	Mangala
Reservoir Pressure	psi	1404
Reservoir Temperature	deg C	65
OWC	m TVDSS	960
GOR	scf/stb	198
API Gravity	°API	28
Wax Content	wt %	22
Max /Min Pour Point	° C	36-39 (live)
		42-48 (dead)
WAT	° C	62
WDT	° C	85
Oil Viscosity at Reservoir conditions (65 deg C)	cP	17
TDS (Formation Water)	mg/l	~ 9600
CO_2 in gas phase	mole %	25%
N_2	mole %	0.31%

Table 1: Mangala Fatehgarh Reservoir & Fluid Properties

All the existing artificial lift forms were screened and evaluated before finalizing Jet pump as the most suitable lift. The evaluation was based on mainly addressing the unique flow assurance challenges of Mangala with target production range from the deviated wells in the range of 1500-6000 blpd.

Sucker Rod Pump (SRP). Due to the relatively high flow rate requirements, conventional pumping units were not capable of lifting at the desired rates. Long stroke units would be required to be installed with larger pumps. The main reasons for not considering this method of artificial lift were:

- Well pad development concept with cellar design to ensure X-mas tree below ground level for rapid rig movement.
- Requirement of frequent workover for rod / pump change out.
- Hot water circulation requirement for flow assurance challenges.

Progressing Cavity Pump (PCP). PCP was eliminated in the screening process due inability of the known elastomers to withstand the CO_2 levels in the crude. In addition to this, high speed (rpm) would have been

required to lift the fluid rates expected from the Mangala wells and this would have meant high wear and tear resulting in high workover frequency. The additional reasons for not considering this method of artificial lift were:

- High risk of localized tubing wears in deviated wells from PCP rod system.
- Flow assurance and wax management during well transient conditions could not be addressed adequately.
- Very few applications worldwide on similar high production rates along with general lack of industry analogue.
- Inadequate flexibility in wax removal from the tubing.

Gas Lift. Initially, **g**as lift was considered as the technically most viable option. This was also considered in the Front End Engineering & Design (FEED) study for the surface facilities. The ability to lift a wide range of flow rates, overall simplicity of system, low well installation cost, ease of well intervention and wax removal, ability to handle sand production and ease of chemical injection, were some of the advantages due to which this was considered the preferred artificial lift option in the beginning.

However, poor injection gas quality due to high CO_2, inadequate supply of gas, high risk of casing corrosion and inability to provide downhole flow assurance were the major reasons which eventually led to disqualification of gas lift.

Electrical Submersible Pump. ESPs are well suited for lifting fluid volumes at more efficient rates than other lifts. ESPs were not considered at the time of selection for deviated wells because of:

- High Installation and workover cost.
- Limited ESP operating experience.
- Requirement of downhole hot water circulation for flow assurance issues.

ESPs were selected as mode of artificial lift for the higher production capacity horizontal wells

Jet Pump. Jet pump was selected as the artificial lift system for Mangala heavy and light producer deviated wells. Main reasons for Jet pump selection were:

- Provides down-hole flow assurance by utilizing hot water power fluid already planned to me made available at well pads for surface flow assurance and hot water flooding in the reservoir.
- Provides a medium for chemical injection by mixing the requisite chemicals in the power fluid stream (demulsifier, Corrosion Inhibitor, Scale Inhibitor, etc.)
- Ability to lift a wide range of liquid rates (proven 100 – 6,000 blpd)
- Low workover frequency and ease of installation/retrieval by wire line.
- Relatively simple to operate with no moving parts.

Jet Pump Design

Jet pump is generally designed in two configurations:

a) Reverse flow mode: Power fluid pumped from the casing– tubing annulus with combined formation and power fluid mixture produced from the tubing **(Fig.9)**.

b) Forward flow mode: Power fluid pumped from the tubing with combined formation and power fluid mixture produced from the casing-tubing annulus **(Fig.9)**.

Overall, screening of various forms of artificial lift confirmed that hot water jet pumping was the most suitable lift to address flow assurance issues which was identified as the critical requirement for producing Mangala crude.

Designing of jet pump was carried out for all individual sand units from FM-1 to FM-5 based on well test data

obtained from the exploration and appraisal wells. Sample designs for typical FM-1 and FM-2 wells are shown in **Table: 2**. Based on theses designs, power fluid pressure requirement, power fluid quantity and depth of jet pumping were decided and the entire range of jet pump throat and nozzle combinations with adequate spares were procured.

Typical FM-1 Well

Water Cut	0%	25%	50%	75%	95%
Gas Oil Ratio (scf/stb)	110	110	110	110	110
Target Pump setting depth (ft)	2756	2756	2756	2756	2756
Target flow rate (bbl/d)	3000	3000	3000	3000	3000
Throat and Nozzle Combination	11 C	11 C	11 C	11 C	11 C
Pump Intake Pressure (psi)	1083	1081	1080	1078	1076
Power Fluid Pressure (psi)	1477	1717	1950	2187	2371
Power Fluid Flow Rate (bbl/d)	1552	1673	1776	1876	1949
Hydraulic HP	43	54	65	78	87
Max Possible Flow for N/T (bbl/d)	3145	3195	3247	3305	3351
Power Fluid to Produced Fluid Ratio	0.52	0.56	0.59	0.63	0.65

Typical FM-2 Well

Water Cut	0%	25%	50%	75%	95%
Gas Oil Ratio (scf/stb)	145	145	145	145	145
Target Pump setting depth (ft)	2918	2918	2918	2918	2918
Target flow rate (bbl/d)	3500	3500	3500	3500	3500
Throat and Nozzle Combination	12 C	11 D	11 D	12 C	12 C
Pump Intake Pressure (psi)	1095	1093	1090	1088	1086
Power Fluid Pressure (psi)	1662	1651	1908	2059	2204
Power Fluid Flow Rate (bbl/d)	2179	1670	1784	2384	2461
Hydraulic HP	68	52	64	93	103
Max Possible Flow for N/T (bbl/d)	3861	4255	4384	4224	4334
Power Fluid to Produced Fluid Ratio	0.62	0.48	0.51	0.68	0.70

Table 2: Jet Pump Design for Typical FM-1 and FM-2 Wells

All the Mangala development oil producer wells are designed with sliding sleeves for installation of reverse flow jet pumps easily installed and retrieved using slick line unit which are available in the field on dedicated basis for various well intervention activities.

Jet Pump Field Trial

Mangala field was lined up for production in August 2009 and is currently producing 150,000 bopd. Jet Pump has played a pivotal role in achieving and sustaining the target production of the field **(Fig. 10)**.

First field trial of jet pump was conducted in Mangala Well A in 2010. The trial was carried with the key objectives of validating jet pump performance and to gain operational experience early in the field life. Well A is a light producer well completed in FM-2 sand. This well was on self flow at the time of jet pump trail and the objective was to flow the well at same self flow rate against a higher flowing tubing head pressure. The trial was carried out successfully meeting all the planned objectives. The selected nozzle throat combination was successful in

achieving the self flow rate of 700 bopd **(Table 3)**. Importantly, the field trial also helped to allay the concerns of emulsion formation due to mixing of power fluid and produced fluid within the jet pump.

Mangala Well A Jet Pump Trials					
Sr. No	**Flow Type**	**WHP (psi)**	**Oil Flow rate (bpd)**	**Flowing pressure at PDG**	**Comments**
1	Natural Flow	250	700-800	920	
2	Designed Flow	350	700-800	920	with Jet pump
3	Actual Flow	370	700	920	with Jet pump

Table 3: Mangala Well A Jet Pump Pilot Well Flow Details

Full Field Implementation

As per the design concept, for every barrel of produced fluid 0.7 barrel of power fluid was required. The Jet pump setting depth in the field ranges from 800 – 1000m TVD. Full field jet pump implementation was carried with a philosophy of 'learn and earn more oil' from the jet pumped wells. In order to achieve optimized performance, a process flow chart **(Fig.11)** was prepared and the following key parameters were thoroughly analyzed:

Power Fluid Rate. The available surface power fluid injection pressure at well pads is up to 2500 psi. It was essential to establish the power fluid requirements for different pump sizes (Nozzle-Throat combination) for the available operating conditions. **Table: 4** shows the expected rate for various sizes of Jet pumps.

JP Size	PF pressure (psi)	Expected PF rate (bpd)
6C	1900 - 2000	~500
7C	1900 - 2000	~600
8B	1900 – 2000	~700
8C	1900 - 2000	~700 - 750
9C	1900 - 2000	~850 - 900
12C	1900 - 2000	~1700 - 1800
13C	1900 - 2000	~2300 - 2400
14C	1900 - 2000	~2800 - 3000

14D	1900 - 2000	~3300
15C	1900 - 2000	~4000

Table 4: Expected Power Fluid Rate for Different JP Sizes

Pump Suction Capability. Drawdown on the formation due to jet pumping was considered in the range of 200 to 400 psi during the design phase. In order to establish actual suction capability of jet pumps, 10 candidate wells were selected for initial jet pump installation with memory gauge installed below the pump to investigate the extent of drawdown being created by the jet pump. After operating the wells on jet pump for more than a week in each of these wells, jet pumps and gauges were retrieved and following observations were made:

1. The suction created by the pump ranges from 300 – 800psi. **Fig.12** shows gauge data interpretation for one example well which was installed with 7C jet pump.
2. Control over suction was also established both by reducing power fluid rates as well as by giving back pressure to the pump through wellhead choke. **Fig.13** shows gauge data interpretation depicting increased drawdown by increasing the choke size.
3. No evidence of cavitation damage in the throat and diffuser were observed even at higher level of suction.

With the knowledge of suction capability of the pumps and their power fluid requirement, next task was to build a design basis on various field observations.

Design Process. During early field implementation, different nozzle throat sizes were tried but most of these were C type throat only. C type pumps were chosen because of their intermediate head capabilities among the available R ratio (ratio of area of Nozzle to Throat) pumps. **Fig. 14** shows typical jet pump performance curve.

The observed M ratio (ratio of produced fluid to power fluid rate) for the early installations was in the range of 1.5 – 2. But there were even cases of lower M ratio up to 0.4. Cases of lower M ratio were observed in wells with lower than expected PI with relatively bigger nozzle size JP. These observations help build a case for careful well specific sizing for jet pumps in Mangala.

Based on the actual field data, software based evaluation was conducted to match the drawdown produced by the pumps and power fluid requirements for different nozzle sizes. After completing this rigorous exercise of getting the match for drawdown and power fluid requirement, design software was optimized. This software gave acceptable match within +/- 5% variation in the results.

Mangala field has Multi Phase Flow meters (MPFM) installed at each well pad for metering of the produced fluids from wells and orifice meters installed for power fluid metering. There were issues with the MPFM in measuring the produced fluid, especially in relatively high GOR wells with increased water cut. Since power fluid metering involved measurement of a single phase fluid using simple metering orifice, the effort was concentrated on getting the match of power fluid and measured suction pressures.

The design for the early wells were matched for the measured suction pressure created by the pump and measured power fluid rate for the given nozzle size. Once matched, well models helped in validating the water cut measurements by the MPFM.

Jet Pump Operating Challenges

Insert Cage Damage. It was observed in some of the wells that there was a decline in power fluid rate through jet pump without any changes in surface pumping pressure. Plugging was suspected in the nozzle and hence jet pumps were retrieved to understand the cause of failure. It was found that insert cage which houses the check valve ball gets damaged **(Fig. 15)**.

Similar behavior was observed in a few more wells and all these were the wells with higher nozzle size jet pump which was designed for power fluid range of 4000 – 6000 bpd. It was suspected that insert cage construction is unable to withstand the large momentum of power fluid; hence it was decided to change the metallurgy of the insert cages from 440 C-SS to Inconel 925 and also increase the rib size from ¼” to 3/8”. As part of field trial, jet pumps with new insert cage metallurgy was installed in a few high capacity wells. These trials have been successful with no damage to insert cage after prolonged jet pumping. In future, all the jet pumps are planned to be assembled with insert cages built of Inconel alloy with increased ribs size.

Standing Valve. During initial trials, all the jet pumps were installed after setting a standing valve in the nipple profile below jet pump. This standard practice was followed to avoid any accidental bull heading of power fluid in the well which may occur during unplanned shut-in of the well. These unplanned shut down is mainly due to instrument/electrical or any failure in the surface process downstream of the X- mas tree.

In one of the cased and perforated well, jet pump was installed with standing valve installed in the landing nipple. Well was operated continuously on jet pump for approximately 3 months. There was a decline observed in well production following which it was decided to retrieve the Jet pump and standing valve to inspect any pump damage. After retrieving jet pump, it was found to be in good condition but while retrieving the standing valve, sand fill was found on top of standing valve. This concluded that there has been continuous sand production from the well which settled on top of the standing valve causing restriction to the flow of produced fluid. The standing valve could be retrieved with great difficulty. Based on this observation, all the standing valves from all jet pump wells were retrieved and held up depth was recorded for sand fill in all jet pumped wells. It was also realized that the risk of accidental bull heading of power fluid in the well was low which has been further reduced by putting additional jet pump operating procedure.

Extreme Operating Condition. Few wells in the Mangala field are operating on Jet pump with relatively high GOR of 400 scf/stb. Damage due to cavitation has not been observed so far. The pumps are working without any failure or damage in those wells too where sand production is observed.

Wellbore Cleanout Application. A few screen wells in Mangala had drill-in fluid against the screen section for a considerable period before the wells were brought on production. After lining up these wells for production, the performance was below expectation. Gradient surveys showed a large part of the open hole screen section covered with heavier gradient (mostly drilling fluid). Jet pumping was designed to provide greater drawdown (up to 700 psi) and this helped to successfully lift the heavy fluid without deploying coiled tubing.

In one such well, it was observed that after installing the Jet pump, there was a gradual improvement in the well oil productivity with simultaneous decline in the produced water (heavier fluid) from the well. This well was unable to produce on self-flow against the production header. After the cleanout exercise using jet pump **(Fig.16)**, the well was put on self flow. Thus, jet pumping was proved as an alternative to nitrogen (N_2) lift application.

Stimulation of the wells is also a frequent operation in Mangala wells. Most of these stimulations require artificially lifted flow back and jet pumping has been successfully used as an option for quick and operational solution for the flow back of stimulated wells.

Current Jet Pump Surveillance

Of late, the requirement of jet pumps installation has significantly increased to maintain production from the field with increase in water cut. As a result, the daily surveillance of these large numbers of jet pumps was becoming difficult and time consuming. To streamline the process and to make it less time consuming and more effective, a customized surveillance page has been built in the Digital Oil Field (DOF) application **(Fig.17)**. The surveillance page has enabled the user to monitor the pump's performance in real-time and spot any abnormal behavior quickly. All the parameters on surveillance page can be trended in plots simultaneously on a common time axis. This functionality has helped in analyzing the performance of the pump over an extended period of time. **Fig.18** shows a typical jet pump monitoring page where jet pump power fluid rate was recorded lower than the designed rate. Slick line was mobilized to retrieve the pump and replace it with a new pump.

Presented below are some additional examples which involved utilizing the surveillance page to understand jet pump behavior and helped diagnose the problems associated with the well and artificial lift.

- With the help of monitoring page, a packer failure incident was diagnosed in a jet pump well. During initial field trials, power fluid requirement for the different nozzle throat combination was established with the available surface injection pressure. In the surveillance page it was found that there has been a sudden rise in the jet pump power fluid rate, significantly more than the design rate. This event occurred with simultaneous drop in surface power fluid injection pressure. There was also a drop in THP of the well. All these observations indicated leak path for power fluid in the casing tubing annulus. Immediately, jet pumping was stopped and detailed diagnosis indicated packer failure. After workover of a well with packer failure, a complete packer tear down activity was conducted to understand the reason for failure. Initial analysis indicated that the packer failure happened because the packer slips had inadequate hardness, which caused the slips to not perfectly engage with the production casing. During load conditions, the slips did not take the power fluid load adequately and this caused the load to be transferred to the shear ring. The packers unset when the load exceeded the strength of the shear ring. **(Fig 19)** However, similar failures were reported in other wells which had packers with proper slip heat treatment. At the time of writing this paper, packer failure has been recorded in a total of 8 jet pump wells. It is suspected that cyclical loads caused by fluctuations in the jet pump power fluid pressure, including surface power fluid pump trips have caused the failure of hydraulic set retrievable packers used in the jet pump wells. Detailed investigation on the failed packer type with simulated loads is in progress at the manufacturer's facility. To mitigate this risk, during workovers, the retrievable packer is being replaced either with a semi-permanent packer or with a permanent packer with locator seal assembly with adequate seal length to handle jet pumping loads.

- The surveillance page has helped in identifying other jet pump problems like nozzle plugging, nozzle throat annulus area scaling restrictions etc. The real time surveillance has resulted quickly identifying the problems and reducing the well downtime **(Fig 20)**.

Jet Pump Performance Optimization

With surveillance tool for jet pump in place, the next step was to devise a methodology for optimizing the jet pump performance by continuous monitoring and operate the jet pumps at their maximum possible efficiency.

There will always be change in PI (Productivity Index) of the well due to increase in water cut, GOR, formation damage etc. Such wells will thus require change in the jet pump size for the new operating conditions to operate the system at maximum possible efficiency. To identify such wells, it is required to continuously monitor their pump performance curves.

Performance curves for different R ratio jet pumps have been plotted using available equation in published literature (Corteville et al, 1987). This equation was an extension of the initial work which was done assuming same fluid density of produced fluid and power fluid (Petrie et al, 1983).

Following methodology was adopted for setting up the pump performance monitoring file for Mangala field.
:

- Excel spread sheet has been set up with the performance curve for the given R ratio pump.
- Spread sheet has been linked to the daily production report which provides the pump operating parameters on a daily basis.
- With the help of nodal analysis software which is also linked to the spread sheet, pump results are tabulated in the spread sheet which gets plotted on the pump performance curve.
- The position of the operating point helps in understanding the performance of the pump under current operating parameters. This observation also serves as the basis for decision on jet pump size change, changes in operating parameters, etc. This has even helped to identify wells for stimulation where severe decline in productivity has been observed.

The pump operating points do not exactly lie on the curve due to various simplifying assumptions used in generation of performance curve. However, it gives a fair idea about the performance of the pump It can be seen that the operating point of Well B (**Fig: 21**) is close to the maximum efficiency point whereas for Well C (**Fig: 22**) it is trending towards the lowest efficiency point. Currently, the work on performance monitoring spreadsheets is still under progress to work on two major aspects:

- Increased automation of the file with less manual interference.
- Incorporating the effect of viscosity in the performance curve generation. The current performance curve formulation does not involve the viscosity term. So far, there has been no severe emulsion problem observed in Mangala but emulsion studies on the Mangala crude have predicted increase in emulsion viscosity with water cut. In such scenario, the losses in the mixing chamber of jet pump will be significantly dependent on the Reynolds number of the combined fluid.

Conclusions

Mangala field has been a successful application of jet pumping technology. This lift is playing a very crucial role in sustaining the field production. Its current contribution stands more than 50% of total production from Mangala. The lift is now well established in Mangala with adequate surface infrastructure which can also help in production of the satellite fields located in RJ-ON 90/1 asset. Most importantly, this lift has been able to adequately handle the down hole flow assurance challenges by utilising hot water power fluid, thus mitigating the most significant risk associated with production of waxy Mangala crude from the deviated oil producers.

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Nomenclature

DOF	Digital Oil Field
ESP	Electrical Submersible Pump
FEED	Front End Engineering & Design
GOR	Gas Oil Ratio

JP	Jet Pump
MPFM	Multi Phase Flow Meter
OWC	Oil Water Contact
PCP	Progressing Cavity Pump
PF	Power Fluid
PI	Productiviry Index
SRP	Sucker Rod Pump
SS	Sub Surface
SSD	Sliding Side Door
STOIIP	Stock Tank Oil Initially in Place
TDS	Total Suspended Solids
TVD	True Vertical Depth
UCS	Unconfined Compressive Strength
WAT	Wax Appearance Temperature
WDT	Wax Dissolution Temperature
WHP	Well Head Pressure

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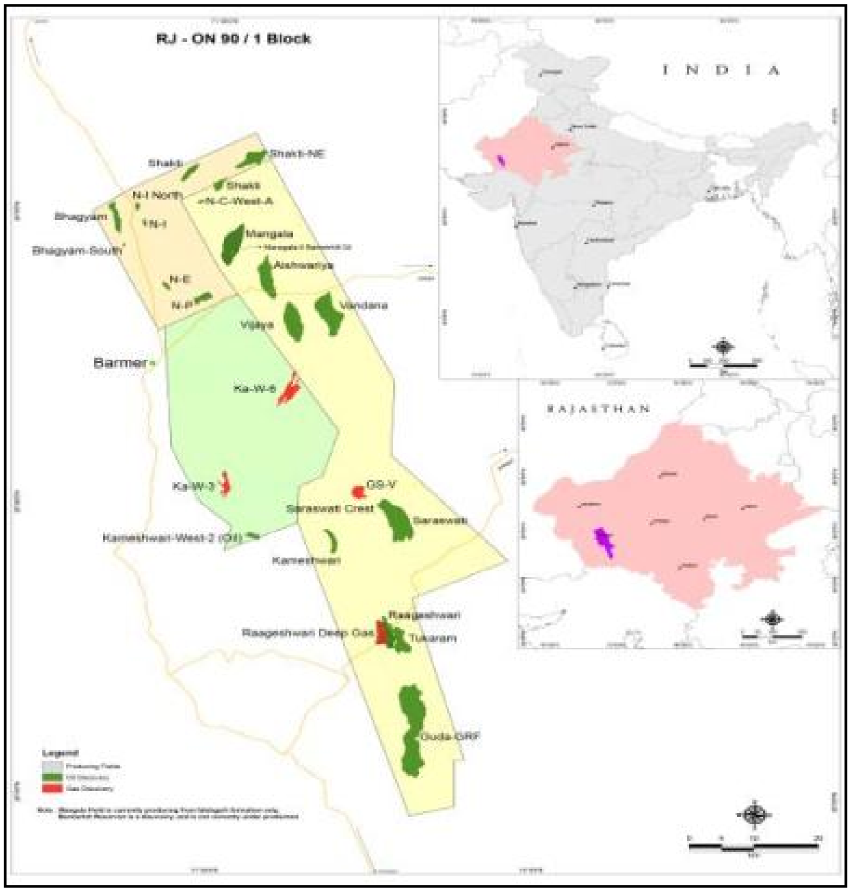


Fig. 1: Mangala Field Location Overview

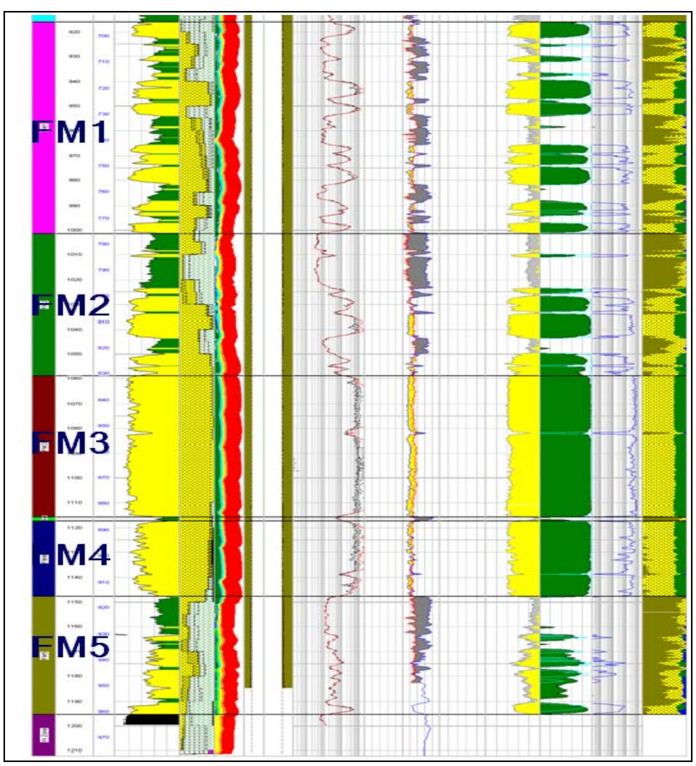


Fig. 2: Type Log of Fatehgarh Sands

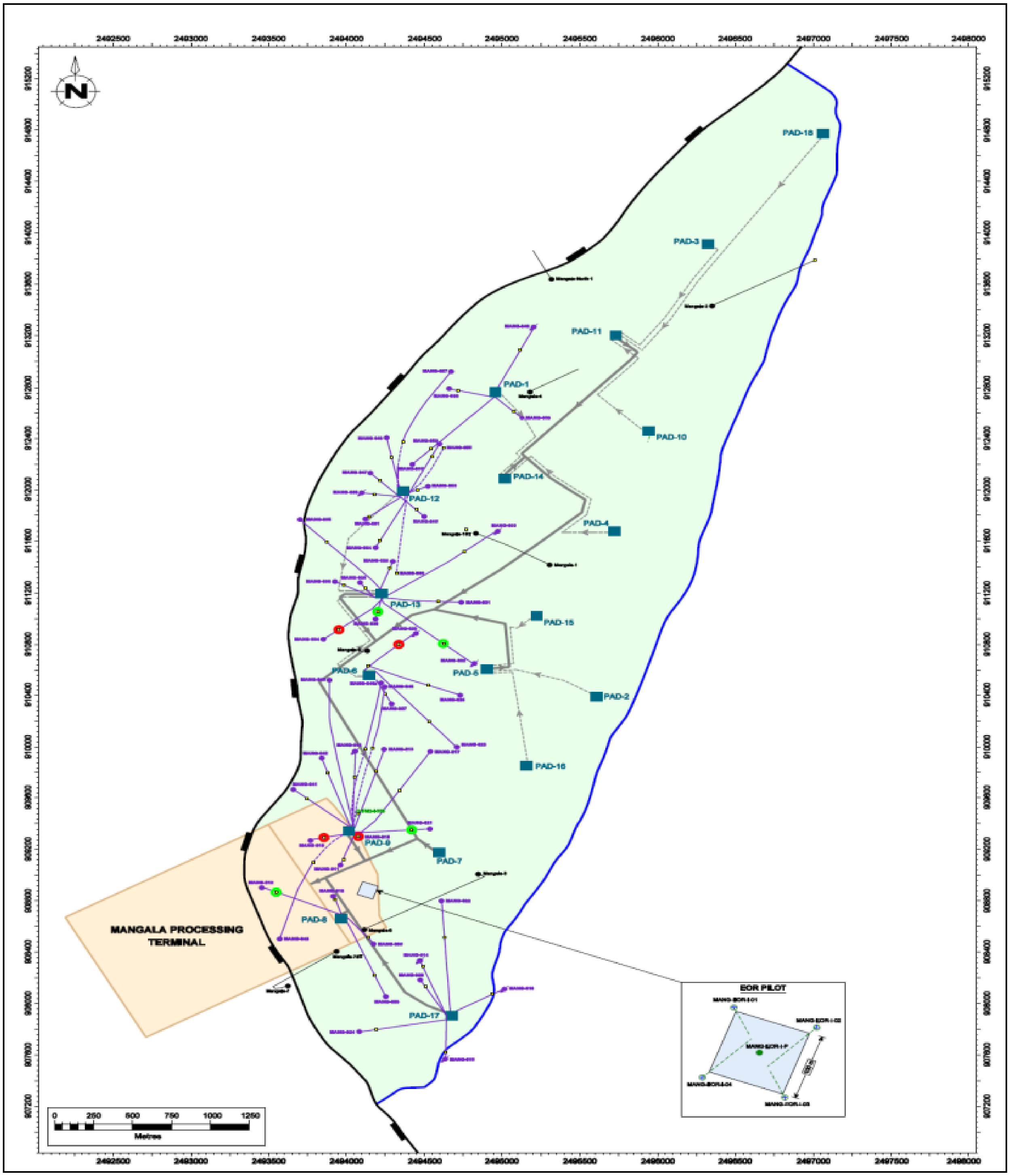


Fig. 3: Well pad and Mangala Processing Terminal

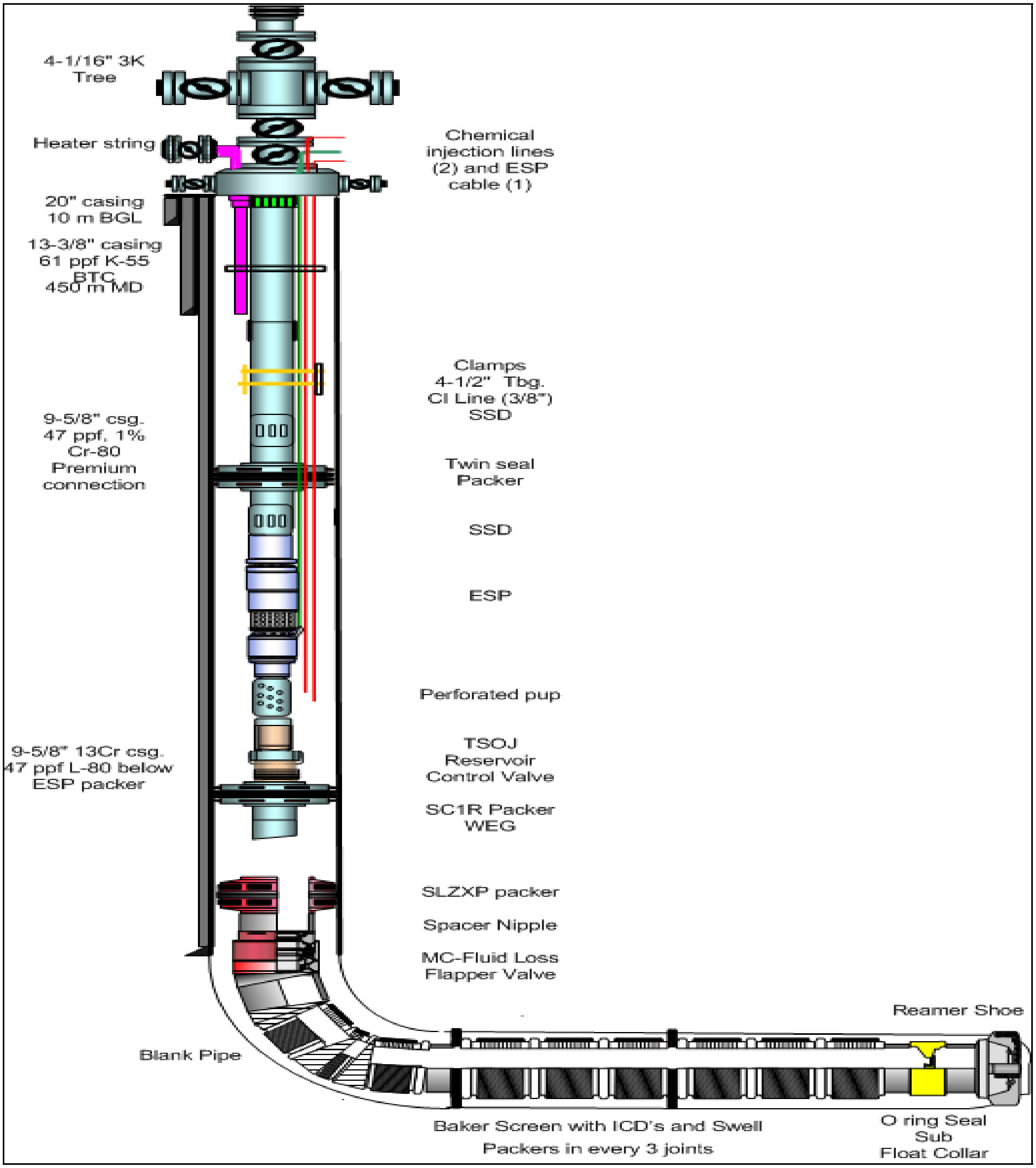


Fig. 4: Horizontal Well Completion

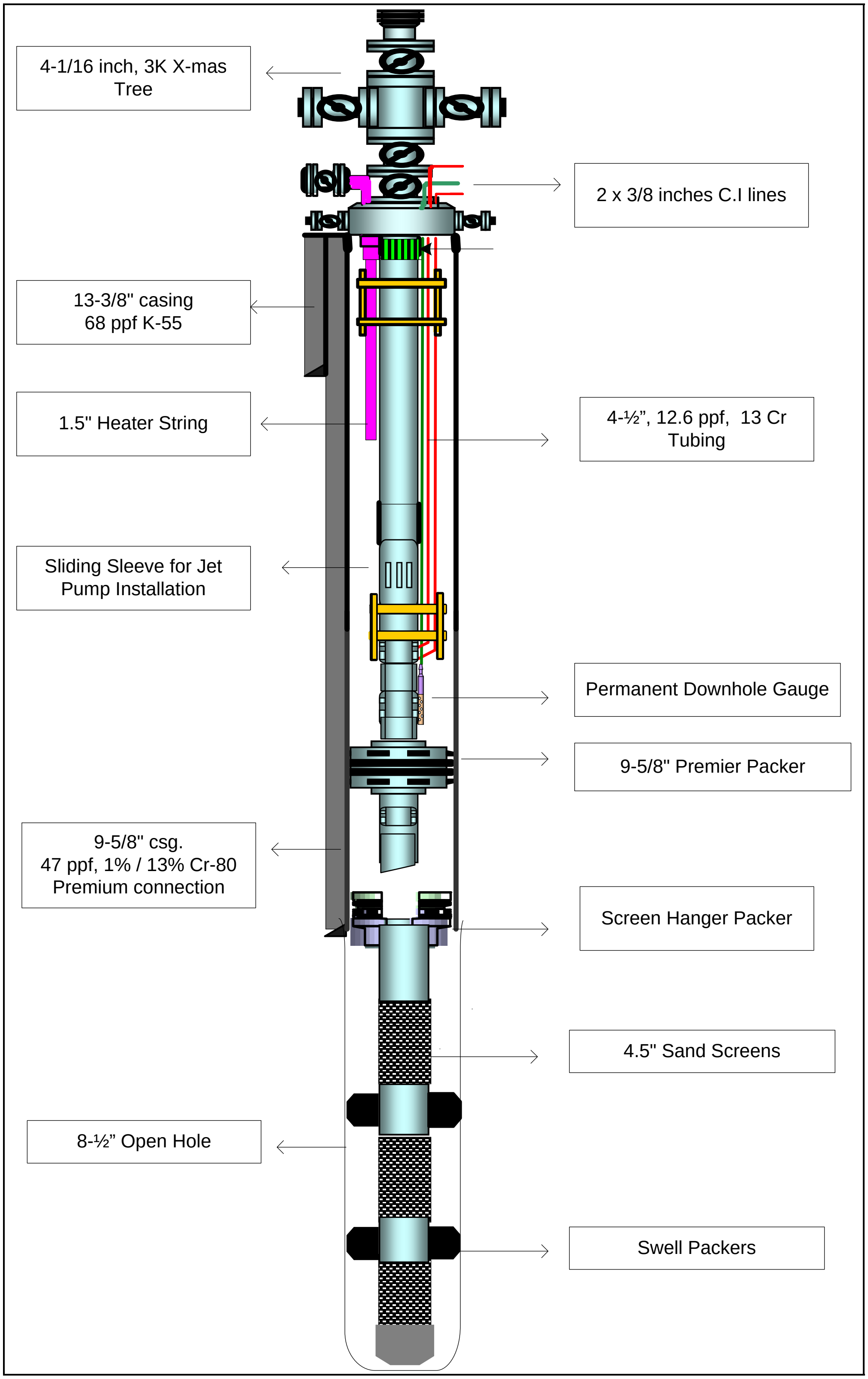


Fig. 5: Heavy Producer Well Completion

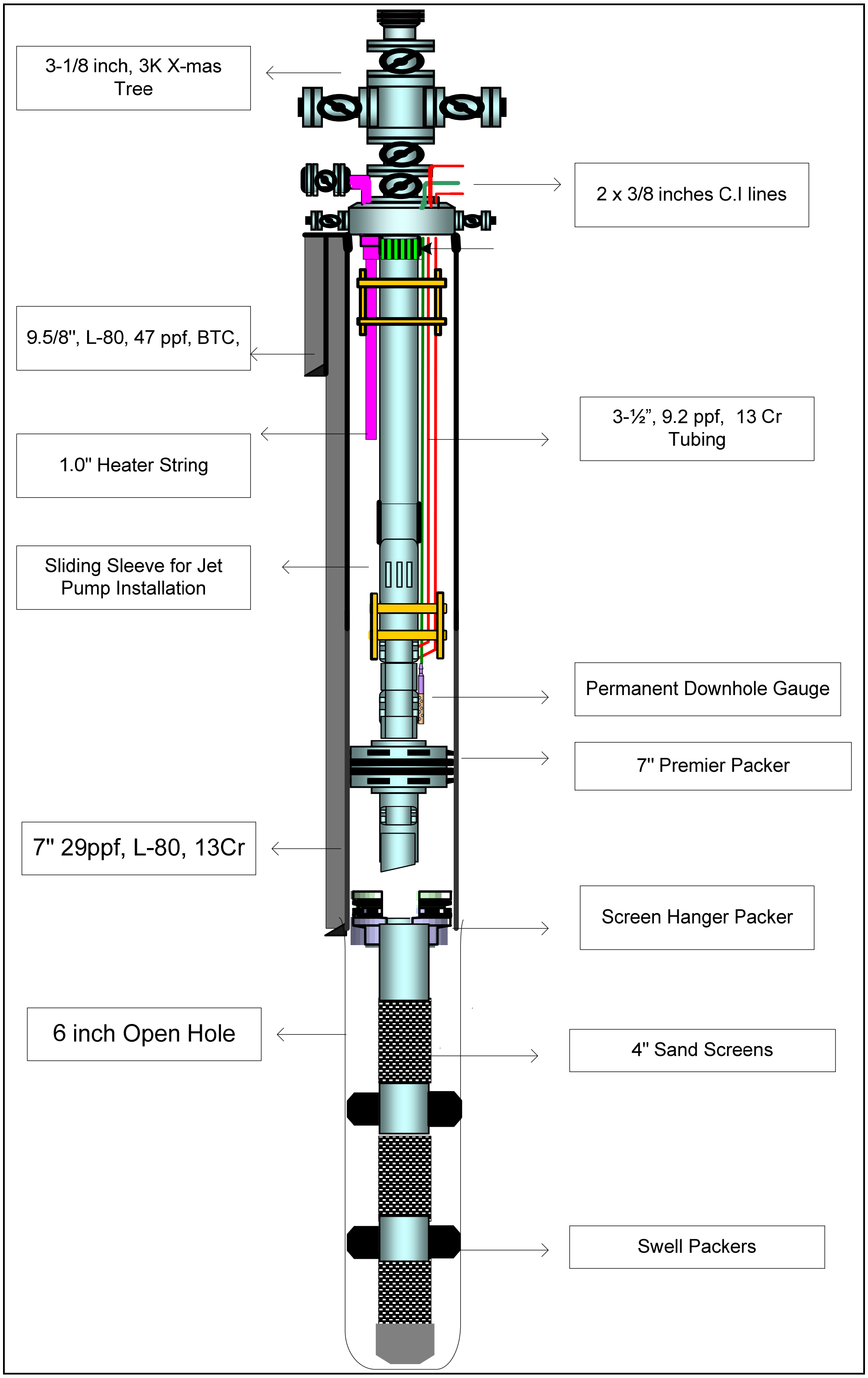


Fig. 6: Light Producer Well Completion

Fig. 7: Waxy Mangala Crude at Surface

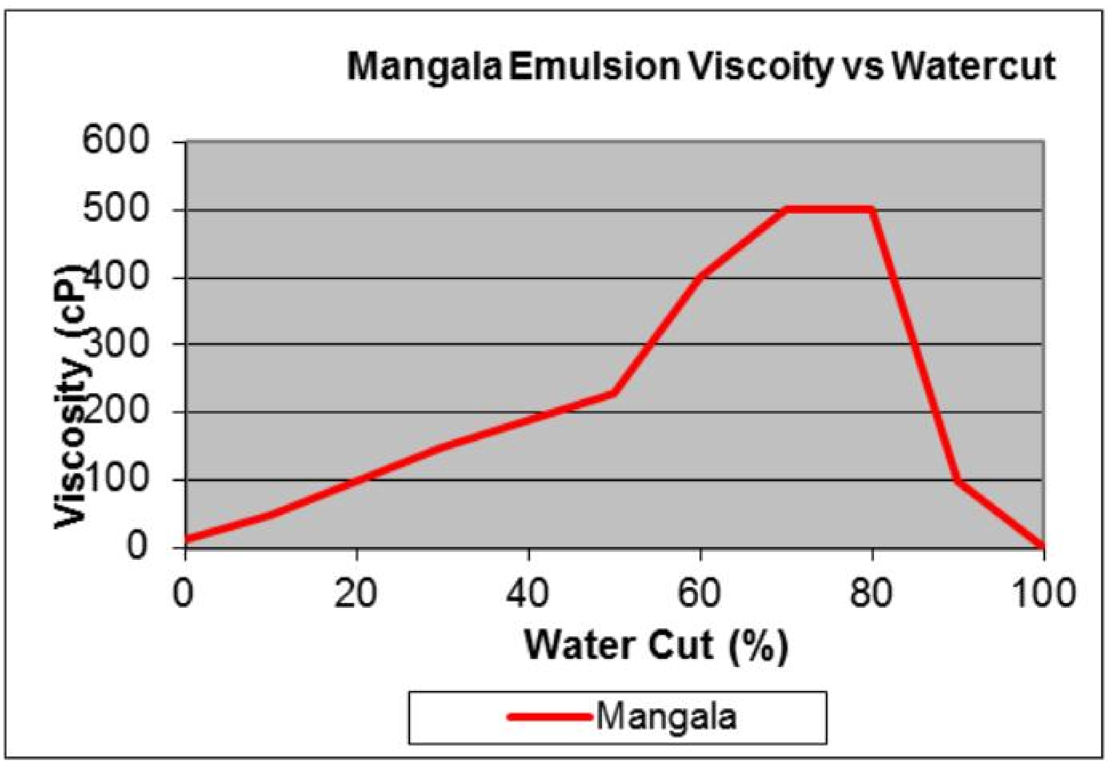


Fig. 8: Expected Emulsion Viscosity Profile of Mangala

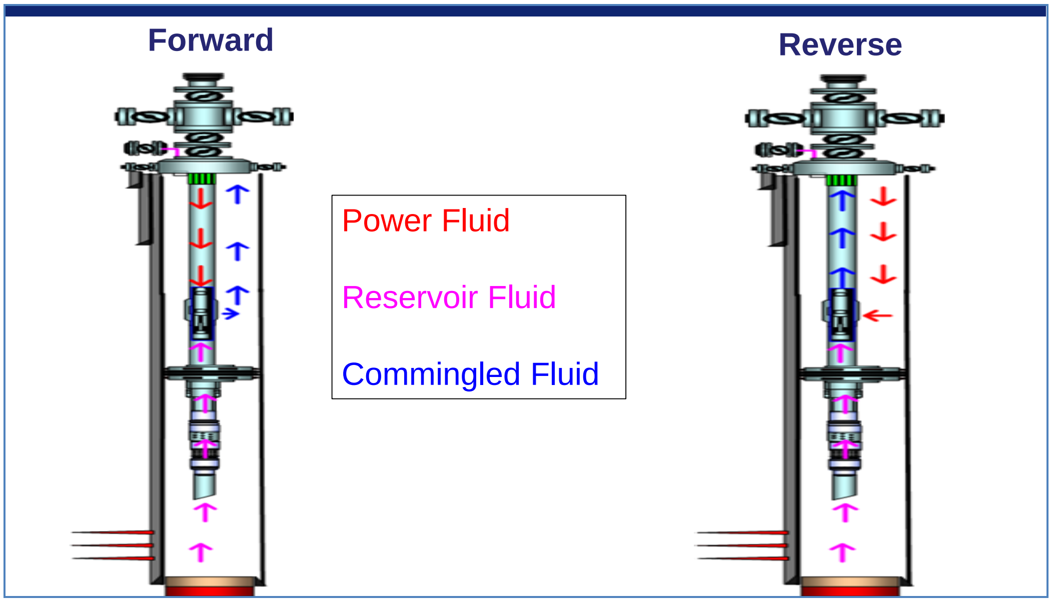


Fig. 9: Jet Pump Types – Forward and Reverse

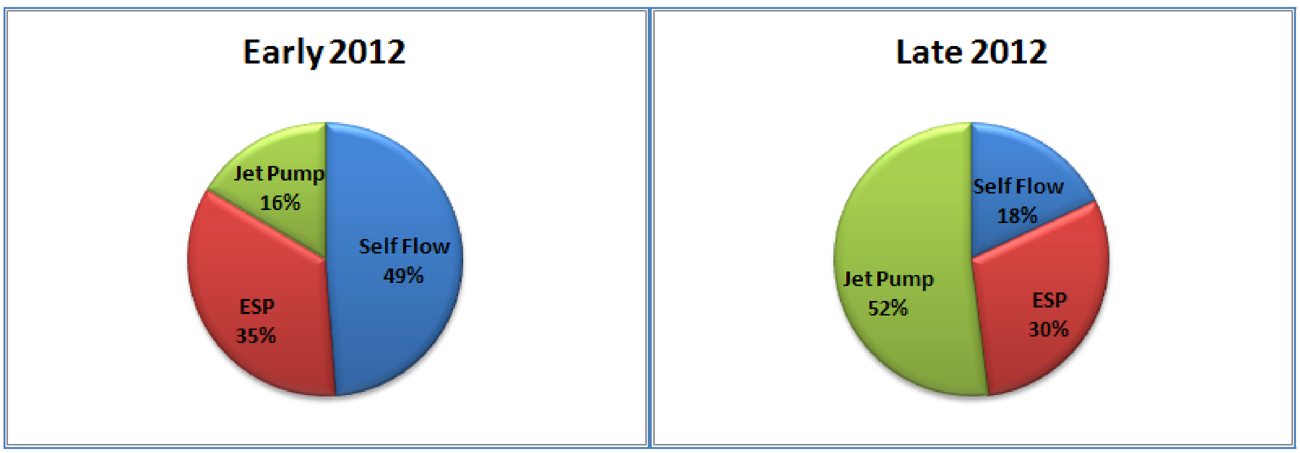


Fig. 10: Contribution of Jet Pump in Mangala Production

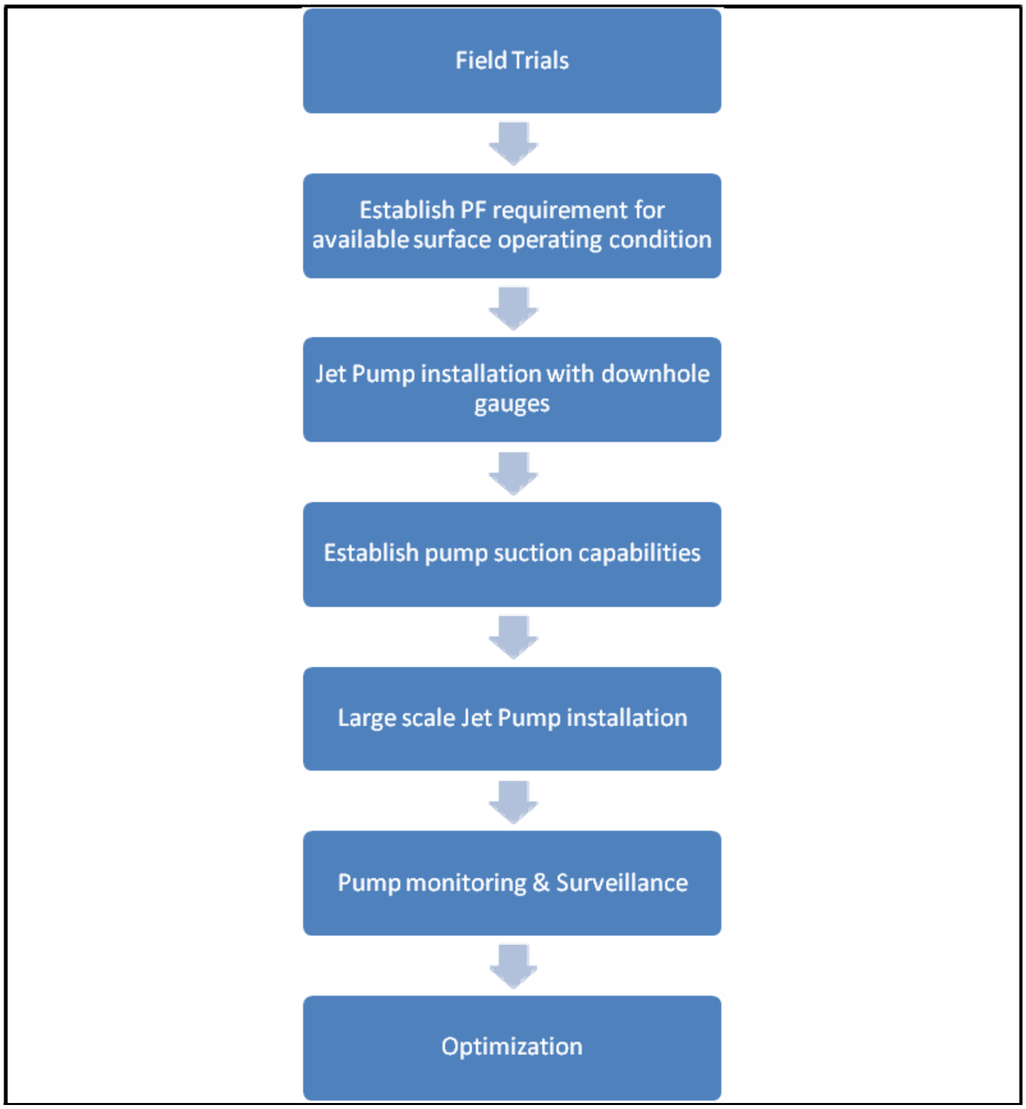


Fig. 11: Process Flowchart from Field Trial to Optimization

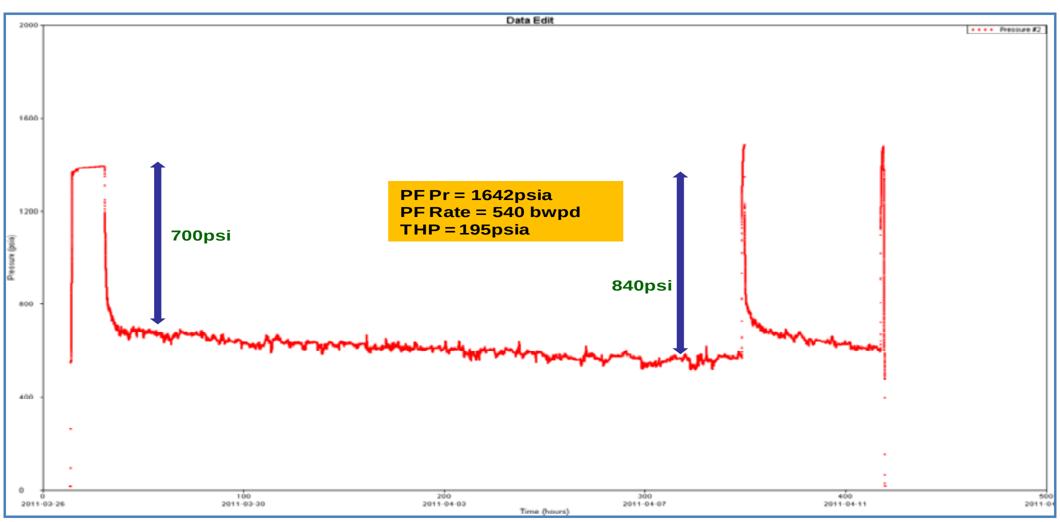


Fig. 12: Jet Pump Gauge Data from a Well with ~800psi Drawdown (Size: 7C)

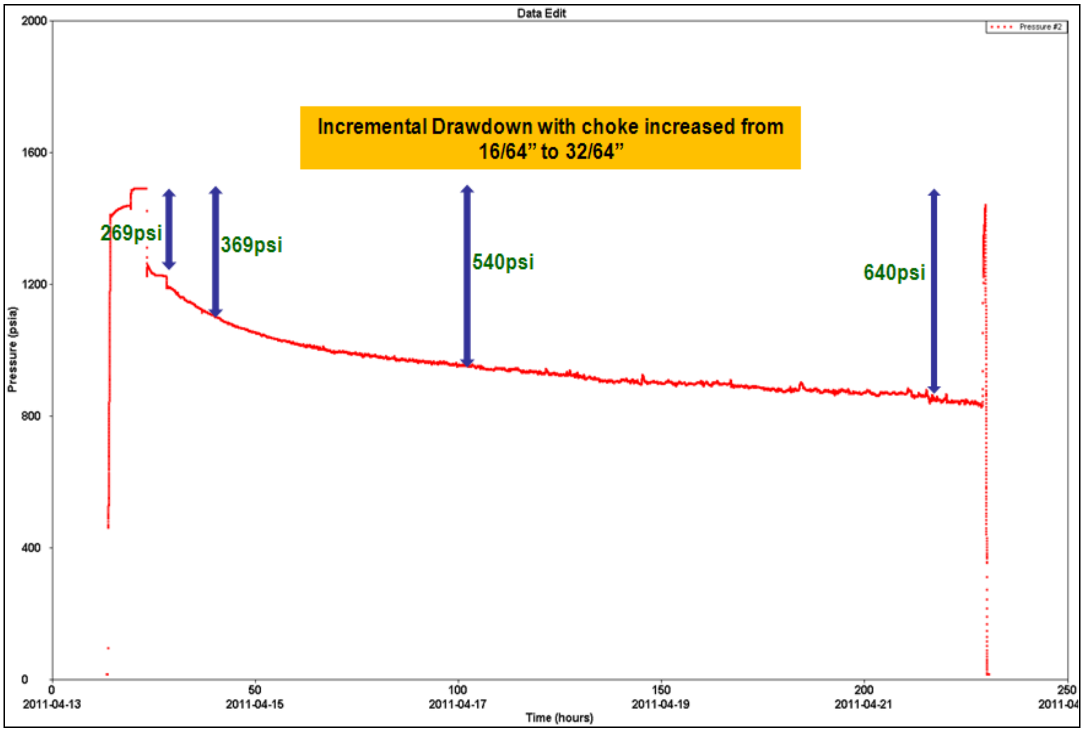


Fig. 13: Jet Pump Gauge Data from a Well Showing Incremental Drawdown

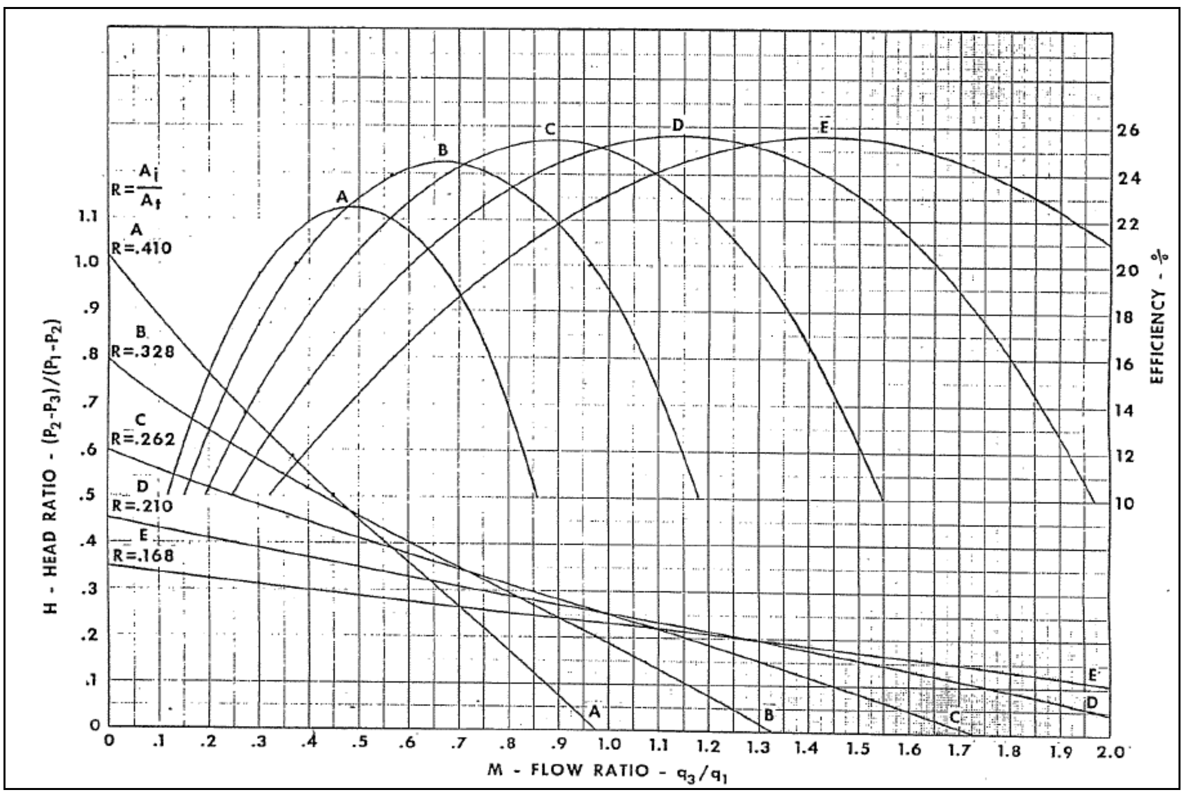


Fig.14: Jet Pump Performance Curves (Courtesy: Technology of Artificial Lift, Kermit E. Brown etal.)

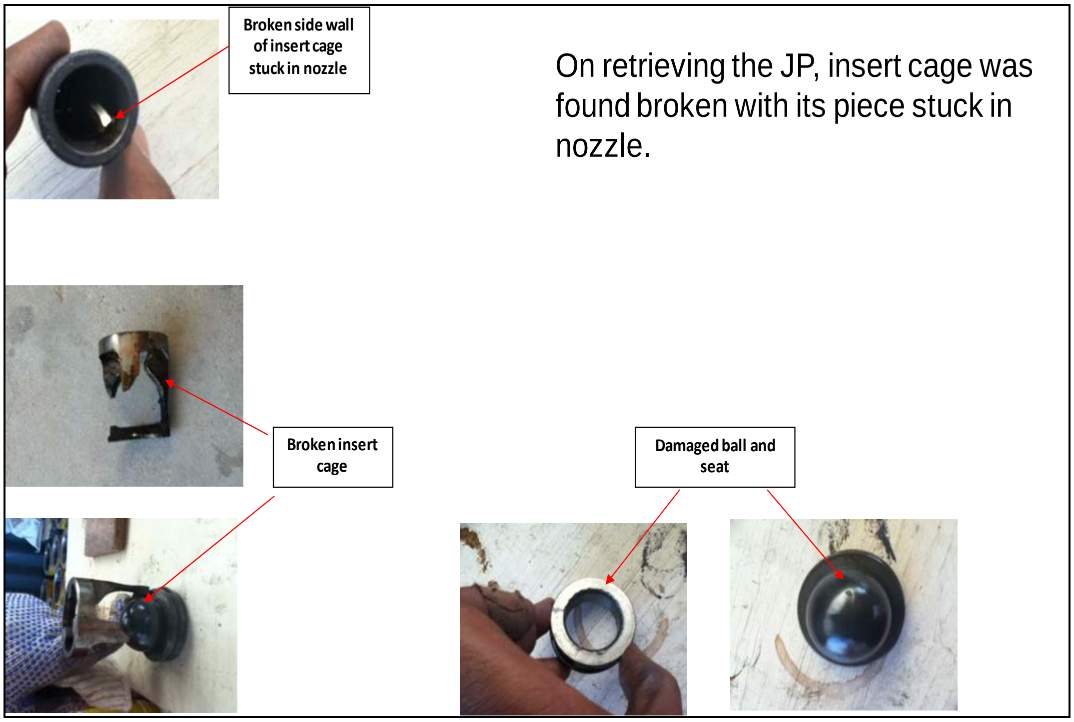


Fig.15: Jet Pump Insert Cage & Ball/ Seat Damage

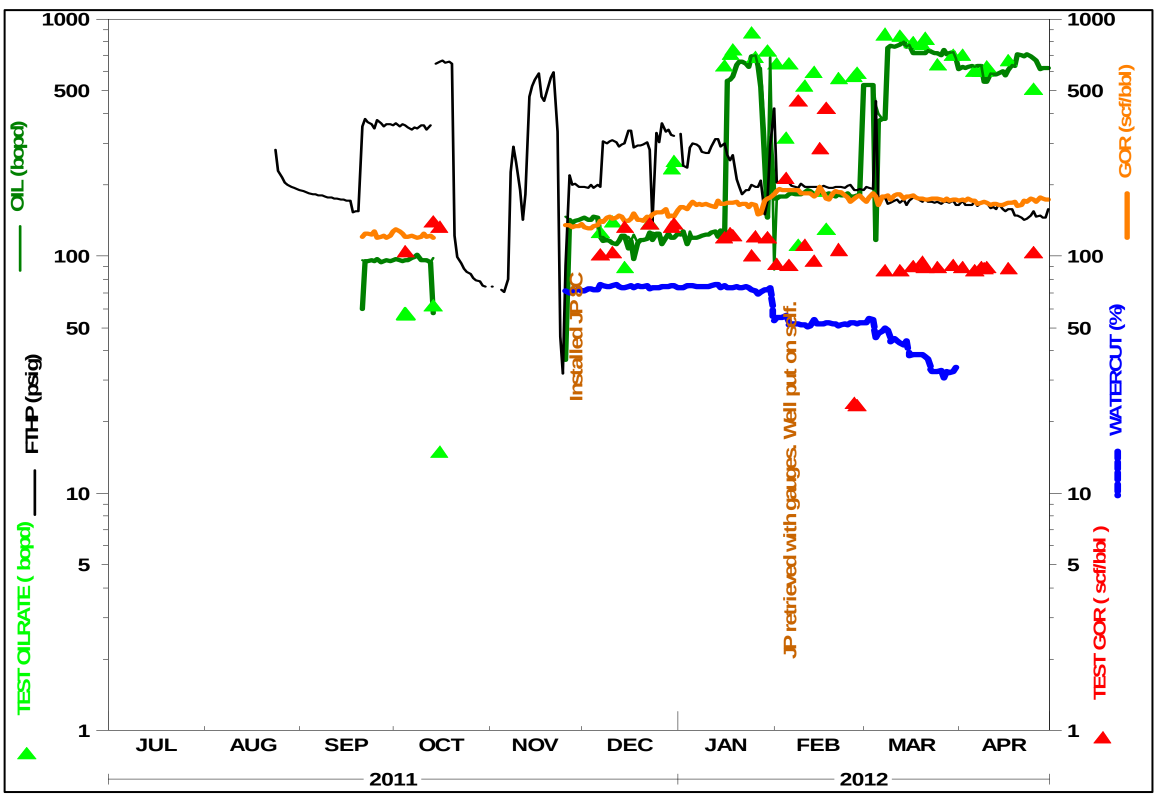
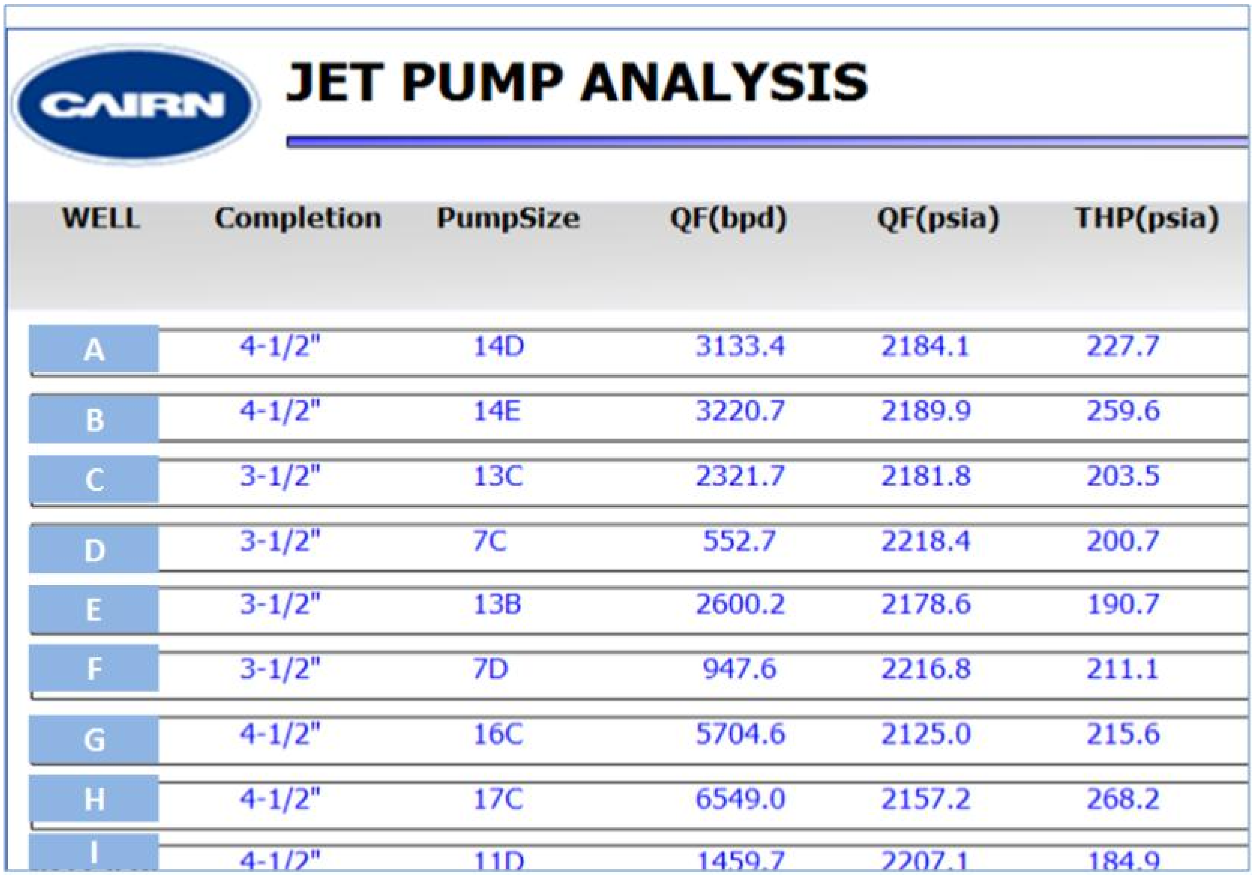


Fig. 16: Jet Pumping to Lift Heavy Gradient Fluid from a Well



JET PUMP ANALYSIS

WELL	Completion	PumpSize	QF(bpd)	QF(psia)	THP(psia)
A	4-1/2"	14D	3133.4	2184.1	227.7
B	4-1/2"	14E	3220.7	2189.9	259.6
C	3-1/2"	13C	2321.7	2181.8	203.5
D	3-1/2"	7C	552.7	2218.4	200.7
E	3-1/2"	13B	2600.2	2178.6	190.7
F	3-1/2"	7D	947.6	2216.8	211.1
G	4-1/2"	16C	5704.6	2125.0	215.6
H	4-1/2"	17C	6549.0	2157.2	268.2
I	4-1/2"	11D	1459.7	2207.1	184.9

Fig.17: Jet Pump Surveillance Page in DOF

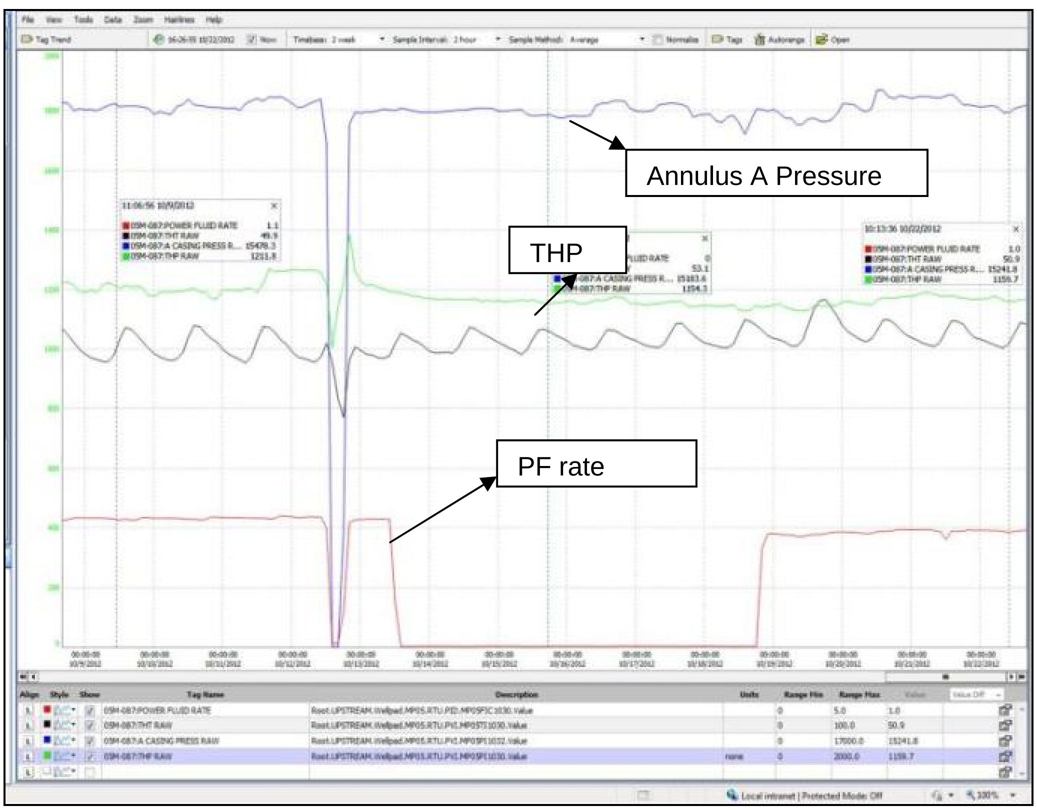


Fig.18: Real Time Jet Pump Monitoring (Lesser Than Designed Power Fluid Rate)

Fig.19: Damaged Production Packer due to Jet Pumping

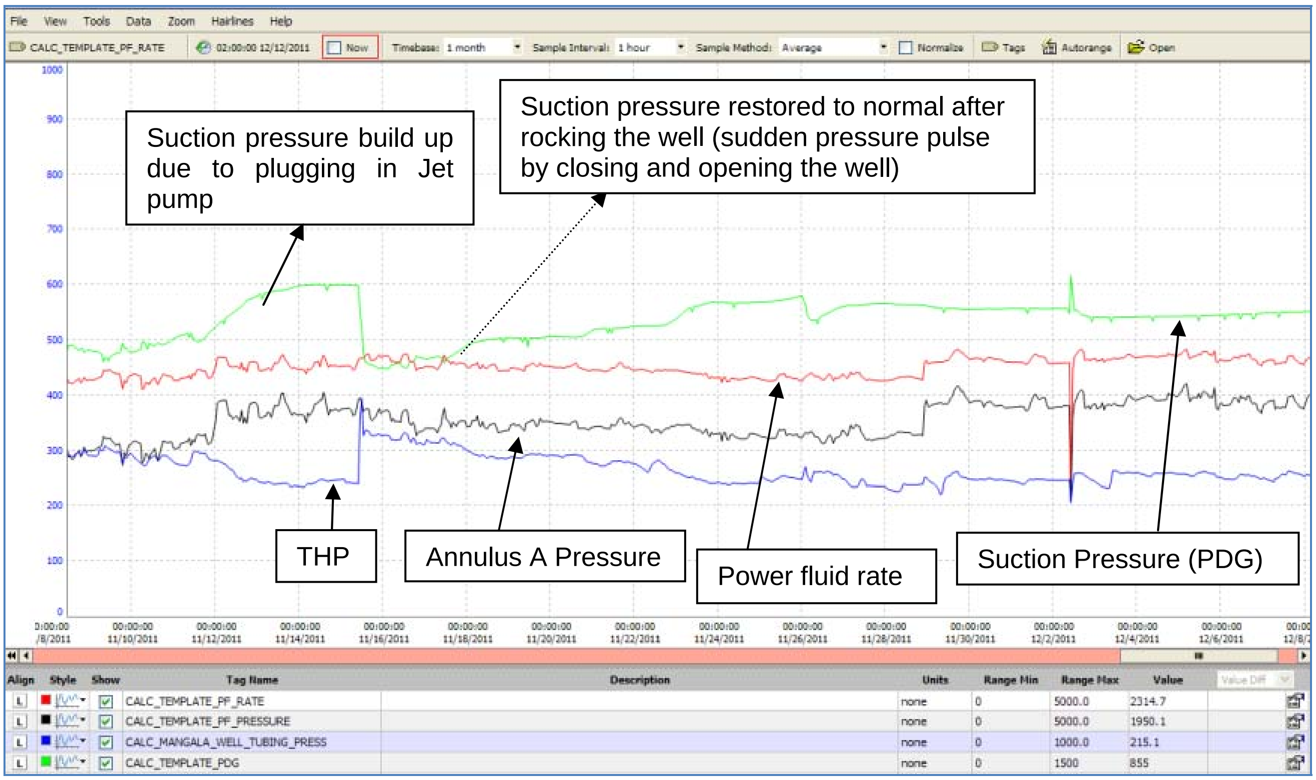


Fig. 20: Plugging of Jet Pump

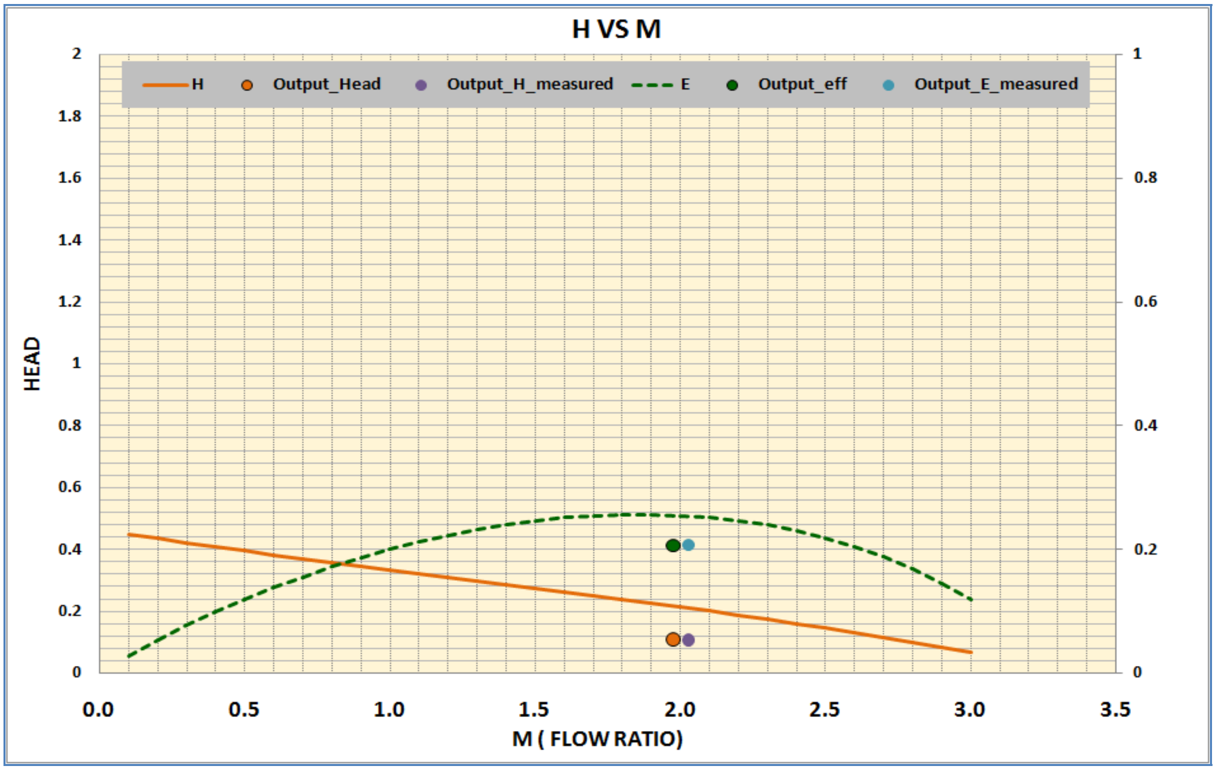


Fig. 21: Well B Operating Near Maximum Efficiency Point

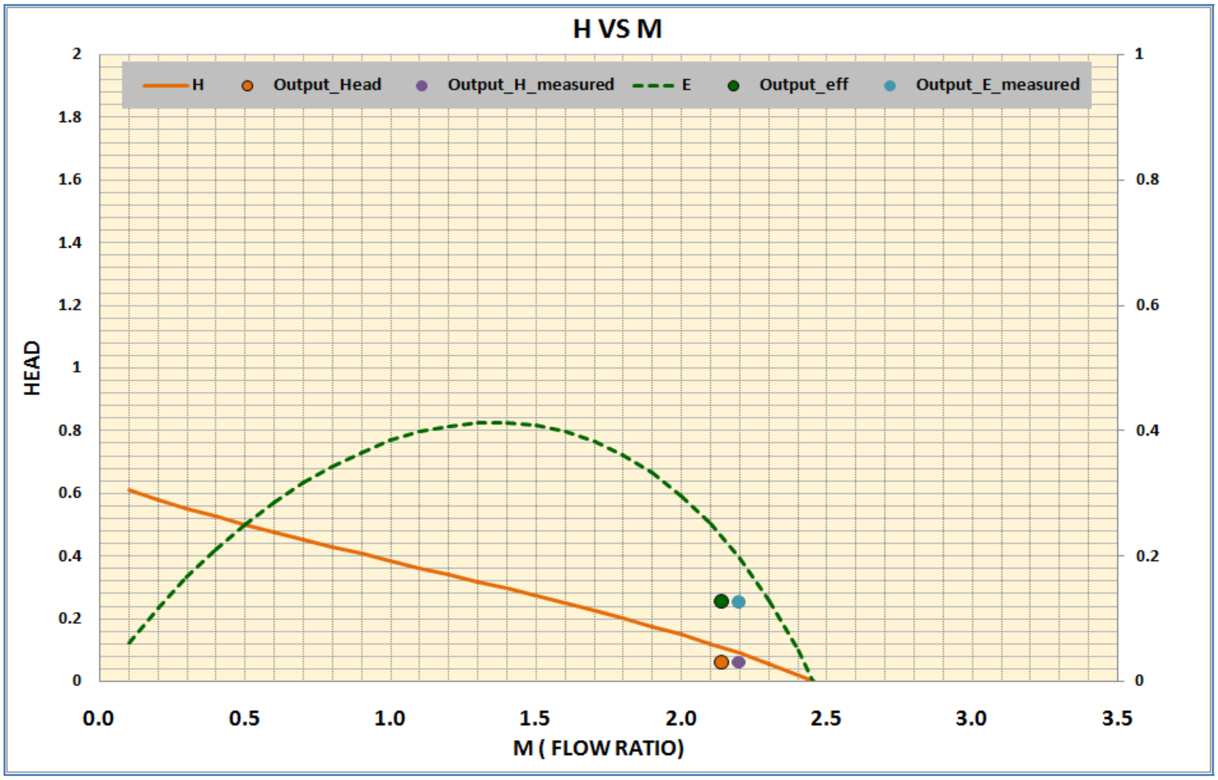


Fig. 22: Well C Operating Near Minimum Efficiency Point